RELIABILITY BENEFITS OF ECONOMIC TRANSMISSION PROJECTS AND ANALYSIS OF CONGESTION IN SOUTHERN CALIFORNIA

CONSULTANT REPORT

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Table of Contents

Introduction 1
Chapter 1: Methodology for Assessing Reliability Benefits 3
Introduction 3
Project Analysis of Benefits and Impacts 4
Devers – Palo Verde No. 2 500 kV 4
PATH 26 6
Method of Evaluating Projects 6
Suggested Procedure 7
Chapter 2: Southern California Transmission Congestion 9
Introduction 9
Transmission System Improvements 10
Reference Price DEC Bids 10
Minimizing MLCC 10
Increase RMR contracts 11
Discussion 11
Market Design Issues 11
Amendment 50 - DEC Bid Reference Prices 12
Optimized Unit Commitment and Dispatch 13
Congestion By Location 14
Transmission Limitations 15
Imperial Valley – Miguel 16
Palo Verde West 17
Other Observations From Operational Data 17
Chapter 3: Southern California Edison and Los Angeles Department of Water and Power Interconnection 19
Introduction 19
Description of Interconnections and Path Ratings 20
Path Flow History 24
Congestion Costs 24
Potential Transmission Improvements 27

List of Figures

Figure 1 Southern California Transmission 16
Figure 2 Southern California Interties........ 20
Figure 3 SCE/LADWP Transmission Detail 21
Figure 4 Sylmar Bus Configuration 22
Figure 5 Sylmar – SCE Simultaneous Nomogram 23
Figure 6 CA ISO Congestion Costs........ 25
Figure 7 Congestion Related Redispatch Costs by Location 26

List of Tables

Table 1 Redispatch Congestion Costs (June 2003 – September 2004)........ 14
Table 2 Palo Verde Area Combined Cycle Generation Additions 18

INTRODUCTION

This report is a compilation of three studies completed by Navigant Consulting, Inc., for the California Energy Commission (Energy Commission) staff and includes:

1. Analysis of the potential reliability benefits of primarily economic transmission projects.

2. An evaluation of the costs and causes of transmission congestion in southern California.

3. A study of the interconnection between Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP).

Chapter 1, "Methodology for Assessing Reliability Benefits," defines potential reliability benefits of transmission projects and then describes a method that could be used to assess these benefits. Chapter 2, "Southern California Transmission Congestion," analyzes the costs and causes of transmission congestion in southern California, focusing on the years 2003 and 2004. Chapter 3, "Southern California Edison and Los Angeles Department of Water and Power Interconnection," describes the interconnection between the two utilities and discusses potential improvements to the interconnection. Overall, these three reports add to the body of work aimed at improving the evaluation of the benefits of new transmission projects and enhance the understanding of transmission congestion issues in southern California.

CHAPTER 1: METHODOLOGY FOR ASSESSING RELIABILITY BENEFITS

Introduction

For transmission, the concept of reliability upgrades is relatively well understood and a deterministic method exists for assessing the best alternative. During the alternative selection process, the economic benefits of each alternative are quantified. The strategic benefits of transmission and generation are just now being articulated. If our long-term goal is to have a “standard practice” technique for providing decision makers with clear and objective information that can be weighed in making resource choices, we need to improve stakeholder consensus on the reliability benefits of transmission projects that are not required to meet established minimum reliability requirements but do increase system reliability.

The goal of this project is to develop recommended measurements and techniques for measuring the reliability benefits of transmission projects that are not required to meet minimum reliability standards.

These benefits could include a reduction in the need to use operating procedures like remedial action schemes (RAS) or special protection systems (SPS) to mitigate the loss of transmission lines or power plants.

The approach taken by Navigant Consulting, Inc., on this project involved the following two steps:

1. Using the Palo Verde – Devers No. 2 Project (PVD2) as an example, we describe and define the potential reliability benefits of a major transmission line where the primary purpose of the project is economic transfers. In other words, the project is not being built because it is required to serve load based on the minimum reliability criteria established by the North American Electric Reliability Council (NERC), the Western Electricity Coordinating Council (WECC), and the California Independent System Operator (CA ISO), but rather it is being built to reduce the cost of energy to electricity consumers by allowing less expensive energy to be imported from other areas.

2. Next, we develop a standardized method for evaluating the reliability benefits defined in step one and qualitatively apply these methods to the Path 26 rating increase from 3,400 megawatts (MW) to 3,700 MW.

Project Analysis of Benefits and Impacts

Palo Verde – Devers No. 2 500 kV

The Palo Verde – Devers No. 2 500 kV Project involves construction of major new transmission and substation components and has been economically justified by the CA ISO[1] and SCE, based on increased imports into the Los Angeles (L.A.) Basin. SCE has submitted an application for construction of the project to the CPUC.[2] With the increased imports, there are inherent benefits to system reliability and benefits to local load areas. Potential reliability impacts are as follows:

- **Improved Service to Load Areas**

  Construction of the project will improve load serving capability at the Devers and Valley substations. As part of the project, 230 kV line overloads are being mitigated by reconductoring the 230 kV lines west of Devers, and voltage support is being provided by the addition of reactive support equipment at the Devers and Valley substations. In the WECC rating process, the project sponsor is required to mitigate all negative impacts and maintain performance at the criteria level, but no "extra" credit is given for incidental and latent benefits that go beyond the minimum requirements.

- **Maintenance Outages**

  Currently, SCE system operations and the CA ISO have concerns about risks to loads in the areas around Devers and Valley when any part of the existing Palo Verde – Devers – Valley – Serrano 500 kV system is taken out of service for maintenance. During these maintenance periods the system is exposed to substantial loss of load for a single forced outage. The Palo Verde – Devers No. 2 500 kV line will not eliminate these concerns but should reduce both the likelihood that the system will be unable to serve loads and the magnitude of a loss-of-load event.

- **Breaker Failure Risks**

  Presently the Devers 500 kV substation is configured as a ring bus; as a result, a breaker failure event could clear the entire 500 kV switchyard. Expansion of the substation facilities (500 kV breakers and a second 500/230 kV transformer) at Devers reduces the probability of a breaker failure event from clearing the entire 500 kV bus.

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[1] California Independent System Operator, Department of Market Analysis & Grid Planning, February 24, 2005, *Economic Evaluation of the Palo Verde-Devers Line No. 2*.

[2] Southern California Edison, April 11, 2005, Application A.05-04-015 for a Certificate of Public Convenience and Necessity Concerning the Palo Verde - Devers No. 2 Transmission Line Project. Currently under review at the California Public Utilities Commission for completeness and compliance with CPUC requirements.

- **Future System Expansion**

  The second Palo Verde – Devers 500 kV line could also facilitate potential construction of a cross tie to Mira Loma or Lugo, or other strengthening of the Mira Loma/Serrano load serving capability. SCE is considering a second 500 kV line from the Devers Substation to the Valley Substation and on to the Serrano Substation to more reliably serve this fast-growing load area.[3]

- **Air Conditioner Motor Stall**

  Actual system faults have demonstrated a tendency of the Valley area 115 kV system to experience motor stall conditions due to the large amounts of single phase residential air conditioner compressor motors without either under-voltage or over-current trip protection. Studies by SCE have verified this exposure. Although the problem requires a more rigorous solution, strengthening the 500 kV system would logically reduce the probability of this problem spreading beyond the Valley Substation area.[4]

- **East of Lugo 500 kV Double Line Outage**

  Even though the East of Lugo 500 kV Double Line Outage has traditionally had a criteria exemption from the WECC, the lines actually run parallel to each other for about 60 miles. With the existing system, and under heavy EOR transfers, this double line outage tends to overload the Lugo – Victorville 500 kV tie. The Palo Verde – Devers No. 2 500 kV line would likely increase the chances of system survival (avoidance of cascading) with added support to the southern end of SCE's system should this double line outage occur.

- **Minimum Load Cost Compensation (MLCC)**

  The CA ISO currently pays generation in the L.A. Basin to operate at minimum load levels to provide emergency ramping in the event of contingencies on the major transmission lines that make up the EOR, west of the Colorado River (WOR), and Southern California Import Transmission (SCIT) Nomogram paths. The CA ISO has described an economic benefit for the DPV2 Project based on a reduced need for MLCC because the project makes the limiting critical line outage a smaller component of the EOR, WOR, and SCIT paths, thereby reducing the MLCC. While this benefit is purely economic in nature, it was not captured by the Transmission Economic Assessment Methodology (TEAM) using

[3] California Independent System Operator, presentation and discussion by Mr. Chuck Wu regarding Transmission System & Long Range Study CA ISO Controlled SCE Transmission 2006-2015 Expansion Plan at the stakeholders meeting June 30, 2005, Agenda Item 3.

[4] Southern California Edison, December 10, 2004, presentation on "Induction Motor Load" by Garry Chinn at SCE's 2005-2014 transmission assessment stakeholder meeting.

Drayton Analytics' PLEXOS model which was used to assess the economics of the Palo Verde—Devers No. 2 project.[5]

Path 26

The Path 26 rating increase from 3,400 MW to 3,700 MW was attained only by increasing the Midway Substation generation drop RAS to 1,400 MW. With this expanded generation dropping scheme the 300 MW north-to-south rating increase is achieved. However, without new line construction, it could be argued that the project actually decreases reliability because a double line loss and failure of the RAS (although unlikely) could have potentially severe consequences to the WECC system. This is the inherent result of a project that increases transfers without the construction of new lines. However, even though reliability is reduced, the project still more than meets all applicable reliability criteria.

Method of Evaluating Projects

A project that increases transfer capability over a path, increases imports into a constrained area, and constructs transmission lines that fully carry a MW loading equal to or greater than the requested path rating increase will generally have positive impacts on the WECC system and regional reliability. Provided that the project is terminated correctly with adequate substation breaker configurations and other substation equipment, the project can have a beneficial impact to local reliability issues as well. This is best demonstrated by the Palo Verde – Devers No.2 Project.

The Path 15 Upgrade (Gates – Los Banos #3 500 kV Line) was added to a system already operating with two 500 kV lines and a generation and load drop RAS. If removal of the RAS had been imposed when the third line was added, there would have been little if any rating increase. The use of the RAS was therefore maintained in order to obtain a 1,500 MW path rating increase. Given that Path 15 actual loadings have probably not increased to fill the full 1,500 MW upgrade, the number of hours that the generation and load drop RAS is armed has probably been reduced from what it was with the two-line system. For this reason, there could be a small, temporary improvement to system reliability. There is a low probability but extreme consequences risk added for a three-line outage of Path 15. During high Path 15 transfer conditions, this three-line outage would likely result in uncontrolled islanding of the WECC system.

A rating increase project that constructs no new transmission, no substation additions (other than replacement of thermally limiting elements), and no active voltage support devices, but relies only upon increasing amounts of either generation dropping or worse yet, load dropping, can only have a negative impact to

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[5] PLEXOS is a market simulation tool by Drayton Analytics, [http://www.draytonanalytics.com/plexos_home.asp]. PLEXOS is the market modeling tool selected for the CA ISO's TEAM approach.

system reliability. This scenario is demonstrated by the Path 26 upgrade from 3,400 to 3,700 MW. The economics of this project work because the project increases the path rating with an inexpensive RAS. The long-term difficulty of relying on RAS for upgrades is that, once installed and relied upon for transfers, RAS almost never goes away. Once the RAS is installed, new line construction projects have to incorporate it or work around it. Otherwise, the new project is unlikely to be cost-effective.

It should be noted that RAS are generally selected because they are far cheaper and easier to permit and construct than the transmission facilities that would otherwise be required. If communication paths are in place, these schemes typically can be implemented for several hundred thousand dollars or less while the Path 15 line construction cost was in the range of $2 million per mile. It should also be noted that RAS, when properly designed and implemented, are capable of fully complying with the NERC,[6] WECC,[7] and CA ISO[8] reliability criteria.

Suggested Procedure

To assess any benefits or latent benefits, the following logical steps could be taken:

1. Create a base case by taking a powerflow model representing the year of expected completion of the project and loading the path(s) in question to existing limits. Run the known critical contingencies.

2. To the base case in Step 1, add the proposed project and load the line/path to the new proposed rating.

3. Based on knowledge of performance issues or concerns in the areas adjacent to the project, hypothesize some potential benefits (as listed for the PVD2 example), take single and multiple contingencies and compare performance to the starting case.

4. To the extent possible, increase loads in the local areas adjacent to the project to determine if load-serving capability shows potential benefits.

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[6] North American Electric Reliability Council, Reliability Standards, Transmission Operations and Transmission Planning, [http://www.nerc.com/~filez/standards/Reliability_Standards.html], (September 16, 2005).

[7] Western Electricity Coordinating Council, Reliability Criteria, Updated April 6, 2005, [http://www.wecc.biz/documents/library/procedures/CriteriaMaster.pdf].

[8] California Independent System Operator, Planning Standards, February 7, 2002, [http://www2.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf], (September 16, 2005).

5. Analyze various maintenance outage scenarios for benefits to operations and reduced risks to load areas. Often these issues are not considered in project rating studies and are left up to operating staff after the project is completed.

6. Analyze breaker failure scenarios to check if the project reduces the chances of load loss.

7. To the extent possible, take the pre-project base case and scale loads in the local area out to ten years or more of projected growth. Run critical contingencies to check for any future reliability issues that may arise. Compare these results to the post-project case to determine if there are any latent reliability benefits in the long term. Evaluate any cost savings by elimination of the need for any reliability projects.

CHAPTER 2: SOUTHERN CALIFORNIA TRANSMISSION CONGESTION

Introduction

Beginning in mid 2003 and continuing through 2004, costs associated with managing congestion at the southern boundary of the CA ISO-controlled grid increased significantly. These increased costs are largely attributed to resolving unfeasible forward energy schedules from new generation in the Palo Verde (PV) and Imperial Valley areas.

The scope of CA ISO congestion management on forward market schedules is limited to inter-zonal transmission paths and ignores any potential congestion on intra-zonal constraints. By design, the CA ISO manages intra-zonal congestion in real time (RT) by re-dispatching resources first by market incremental (INC) and detrimental (DEC) energy bids; Then, if necessary, by dispatching Reliability-Must-Run (RMR), Out-of-Sequence (OOS), and Out-of-Market (OOM) resources, in that order.

Furthermore, the CA ISO has the ability to forecast intra-zonal congestion and to take action to minimize the likelihood of curtailing load due to insufficient available supply resources in chronically constrained areas of the grid. When such congestion is anticipated, the CA ISO has authority to commit resources in strategic locations in order to ensure sufficient on-line capacity to reliably meet forecasted demand. The cost of these resource commitment instructions is a large component of overall intra-zonal congestion management.

Unfeasible forward scheduling of PV area generation and Mexican generation (border generation) near Imperial Valley resulted in 2,982 hours of congestion between July 1, 2003, and March 31, 2004, or 45 percent of the total hours. Congestion occurred on the Imperial Valley – Miguel 500 kilovolt (kV) line and on the PV – West branch group (which includes the PV – Devers 500 and Hassayampa – North Gila 500 kV lines).

Real-time congestion costs are generally broken down into three categories:

1. Costs due to redispatching market resources.

2. Costs due to dispatching RMR units.

3. MLCC associated with committing units for locational reliability.

The congestion costs associated with unfeasible schedules from the border generation were largely due to RMR dispatches and market INC and DEC dispatches, with very little MLCC.[9]

Congestion management at a nodal level in the forward market, as proposed in the CA ISO Market Redesign and Technology Upgrade (MRTU) Project, is seen as the ultimate fix to the unfeasible forward scheduling issue. However, several steps have been taken to address

[9] California Independent System Operator, Department of Market Analysis, Revised 10/7/2004, *Intra-Zonal Congestion Management Impacts*.

the sky-rocketing congestion management costs of chronically congested intra-zonal constraints, including:

1. Improving the transmission system.
2. Amendment 50 – Reference DEC bids.
3. Improving the must offer unit commitment process to minimize MLCC.
4. Contracting for more RMR resources in areas of chronic intra-zonal congestion.

Transmission System Improvements

Several transmission projects have been constructed in the last two years to help mitigate the congestion occurring in southern California. Some of these projects are:

- Additional 500/230 kV transformers at Imperial Valley and Miguel.
- A new Mission – Miguel 230 kV transmission line.
- Path 26 RAS expansion.
- South of Lugo RAS.

In addition, several new transmission reinforcement projects are in various stages of the planning and construction process. These projects include:

- Upgrades to the series capacitors on the Palo Verde – Devers and Hassayampa – North Gila – Imperial Valley 500 kV lines and other system improvements the West of River (WOR) short-term upgrade project).
- The EOR 9000+ series capacitor upgrade project.
- The Palo Verde – Devers No. 2 500 kV transmission line.

Reference Price DEC Bids

Beginning in 2003, the CA ISO began replacing market DEC bids with resource-specific reference DEC bid curves. This change was an effort to minimize the exercise of market power by resources that were likely to be overscheduled in the forward market and therefore strong candidates to be decremented (DEC'ed) in RT. By using the reference bid price, the resource is not able to game the DEC market to the extent that might otherwise be the case.

Minimizing MLCC

Resources that are issued commitment instructions by the CA ISO to meet investor-owned utility (IOU) net short requirements are paid MLCC. The CA ISO has significantly improved its software and processes to more accurately determine net short energy needs, and to optimally commit resources to meet these requirements to minimize MLCC.

Increase RMR contracts

In constrained load pocket areas where units are designated as RMR, additional units could be designated or contracted operation levels of designated units increased for the supplemental purpose of congestion relief.

One of the main reasons for all of this recent congestion is that generators scheduling into the CA ISO can develop new plants far faster than the CA ISO or participating transmission owners (PTOs) can build with new transmission. This is a structural problem that cannot be addressed except by significantly reducing the time it takes to complete the WECC rating, environmental permitting, and site licensing processes.

The longer term also holds hope for significant transmission improvements and the transition to a nodal pricing model where pricing sends locational market signals for future generation plant construction and for operation of existing market generators. The goal is to get to "feasible forward market schedules" and nodal pricing signals are intended to do this. Not all congestion ills will be cured, but with the nodal approach, intra-zonal congestion management will move to the forward market.

Discussion

Market Design Issues

The root of the congestion problem originates with the assumption that inter-zonal congestion management on forward energy schedules will resolve most major chronic congestion so that intra-zonal congestion in RT will be minor and infrequent. While the financial incentives are in place for PTOs to build new lines in response to high intra-zonal congestion costs, consumers have paid a high price for the RT management of congestion while the transmission system upgrades are planned, designed, and built.

The CA ISO tariff does allow for new congestion zones to be created, providing a mechanism for moving congestion management of chronically constrained intra-zonal paths out of RT operations and into the forward congestion market. Adding new radially interconnected zones is technically feasible without significant redesign of software or operating procedures. However, adding new imbedded congestion zones is technically difficult and presents significant software and other system and policy changes to the existing CA ISO congestion market. The CA ISO has considered but declined to pursue implementing such significant procedural changes, stating that it is unfeasible to concurrently embark on such an effort simultaneously with the MRTU project that is consuming much of the CA ISO's resources.

Since many of the most chronically congested intra-zonal paths are imbedded in the existing south of Path 15 (SP15) congestion zone, reducing the high congestion costs prior to the MRTU implementation must be addressed by:

1. Transmission system upgrades.

2. Creative market policies and procedures.

3. Optimization tools.

Transmission upgrades that address chronic intra-zonal congestion are discussed in a subsequent section of this report.

To address the high costs of intra-zonal congestion, there have been two successful developments at the CA ISO:

1. Amendment 50 - DEC bid reference prices.

2. Deployment of unit commitment and dispatch economic optimization tools.

Amendment 50 - DEC Bid Reference Prices

Intra-zonal congestion management in RT consists of the CA ISO issuing dispatch instructions to decrease generation from resources that strongly contribute to congestion which may include resources cleared in the forward market. The CA ISO then backfills the needed supply, if necessary, by issuing dispatch instructions to increase generation from other available resources in the following order:

1. Infra-marginal imbalance energy bids.

2. RMR capacity.

3. Extra-marginal imbalance energy.

4. Out-of-market resources.

The cost of re-dispatching resources to resolve intra-zonal congestion is based on the difference between the payments due to resources that were issued incremental dispatch instructions, and the payments due from resources which were issued decremental dispatch instructions. Large intra-zonal congestion costs can occur if incremental and decremental RT bids are left unchecked.

The market design, that assumes robust competition in the bilateral energy market as well as the INC and DEC imbalance energy markets, would naturally minimize RT imbalance energy costs. For example, if revenues to a supply entity were at or close to the marginal cost of that resource, then any revenues earned by forward selling one unit of energy across a known intra-zonal constraint would be very close to the DEC price it will pay in real time to decrease its output by one unit of energy to relieve the intra-zonal constraint.

Without competition in the DEC market among resources that have comparable effectiveness in relieving known intra-zonal constraints, the resource would have no incentive to feasibly schedule the energy in the forward market, since it could expect to pay low or no costs to reduce its dispatch in RT.

However, the CA ISO has installed market rules that contain these costs, buying time until the “true fix” comes on line with MRTU nodal forward market congestion management. These are:

1. Incremental and decremental imbalance energy bid caps.

2. Amendment 50, which among other things, mandates that the CA ISO use reference DEC bids for intra-zonal congestion management.

The “DEC game” is a term that is used to describe the particular bidding strategy in which a scheduling coordinator (SC) submits a forward market schedule for a resource that is likely to be DEC’ed in RT, then submits a large negative DEC bid for the same resources. A negative DEC bid means that the CA ISO pays the generator to reduce its output. Unaddressed, this practice has cost metered demand, particularly in SP15, millions of dollars by paying SCs to reduce supply energy schedules due to predictable RT intra-zonal congestion.

In May 2003, the Federal Energy Regulatory Commission (FERC) approved elements of the CA ISO’s proposed Amendment 50, which helped contain, but not eliminate, the costs associated with the DEC game and intra-zonal congestion management. Specifically, FERC approved the Amendment 50 proposal to use resource specific reference level bid curves in place of market DEC bids to resolve intra-zonal congestion (market DEC bids shall continue to be used for procurement of non congestion related decremental energy).

Optimized Unit Commitment and Dispatch

During the 2000 - 2001 energy crisis in California, the RT imbalance energy market became extremely volatile and costly. Given that the financially-hemorrhaging IOUs were forced to buy much of their energy from the CA ISO RT market, the State Department of Water Resources (DWR) took action to move procurement of a significant portion of California’s IOU demand out of RT. The State signed multiple long-term power purchase contracts on behalf of the IOUs, and began scheduling these resources in the CA ISO forward markets. The residual California IOUs’ energy needs, referred to as net short energy, would be procured in the CA ISO RT market.

However, many of these contracts include provisions that deem the power to be delivered to the congestion zone as scheduled in the CA ISO forward market. California’s IOU procurement of net short energy in RT would then not only include the difference between total forecasted demand and forward scheduled energy, but would also include the procurement of incremental energy to replace unfeasibly scheduled contract power.

FERC issued the “Must Offer” Order in 2001, requiring all thermal generators selling power through the CA ISO to offer their available energy to the CA ISO RT market.[10] The thought was that if all available supply capacity were forced to offer their energy in RT, it would maximize the liquidity of that market and minimize the costs of RT imbalance energy.

Because of minimum start-up time and ramping time constraints on many large supply resources, full compliance with this Order would mean that all large units in California would need to stay up and running, often at minimum load levels, even during off-peak and seasonally mild periods. This is both expensive and against good utility practices.

The CA ISO has implemented a process whereby it assesses the California IOUs’ net short requirement on a day ahead basis, and allow certain units to go off-line for the next day.

[10] 95 FERC ¶61,418, often referred to as the June 19 “Must-Offer” order.

This process seeks to ensure that sufficient capacity is on line and responsive to meet the IOUs' net short demand, but is also optimized for cost minimization and locational requirements. It is important to note that this assessment of IOU net short energy requirements includes a reliability margin for contingencies and anticipated intra-zonal congestion redispatch.

This Must Offer Waiver process was initiated in late 2001, and has undergone significant improvement as late as late 2004. Currently, the CA ISO uses a transmission constrained unit commitment process to optimally commit available resources to meet system and locational net short energy requirements, while minimizing MLCC costs.

As long as energy from these DWR contracted resources (and other bilateral schedules) continue to be scheduled unfeasibly in the forward markets, the CA ISO will need to continue to commit units under the Must Offer authority to maintain reliability, both systemwide and locally. MLCC is paid to all resources operating in compliance with CA ISO Must Offer commitment instructions.

The MLCC component of over-all intra-zonal congestion management costs is significant. Following are percentages of MLCC costs with respect to overall intra-zonal congestion costs: 86 percent (2002), 65 percent (2003), and 69 percent (first two quarters of 2004).[11]

Congestion By Location

Redispatch costs in the CA ISO's Department of Market Analysis (DMA) reports show that from June of 2003 through September of 2004, 85 percent of the redispatch costs were attributable to congestion related to SP15 constraints.[12] Table 1 shows a breakdown of redispatch congestion costs by location. Note that "Vincent" does not include Path 26.

Table 1

Redispatch Congestion Costs

(June 2003 – September 2004)

Congestion Location	Redispatch, MWHrs	Total Redispatch Cost ($)	Percentage (%) of Total Re-dispatch Costs
Sylmar	1,026,742	$35,033,936	33%
Vincent	256,753	$6,775,925	6%
Lugo	437,281	$11,713,814	11%
Miguel	1,702,241	$33,243,141	31%
SCIT	122,696	$3,551,872	3%

[11] The CA ISO has begun to differentiate commitment instructions for (i) system and (ii) zonal, and (iii) local net short requirement separately for cost allocation purposes. However, data presented by the CA ISO represents MLCC total costs, without identifying the breakdown of the three components. These percentages may therefore be high.

[12] California Independent System Operator, DMA, Nov. 5, 2004, Market Analysis Report.

SP15 Total	**3,545,713**	**$90,318,688**	**85%**
Other	617,869	$16,109,376	15%
CA ISO Total	4,163,583	$106,428,064	100%

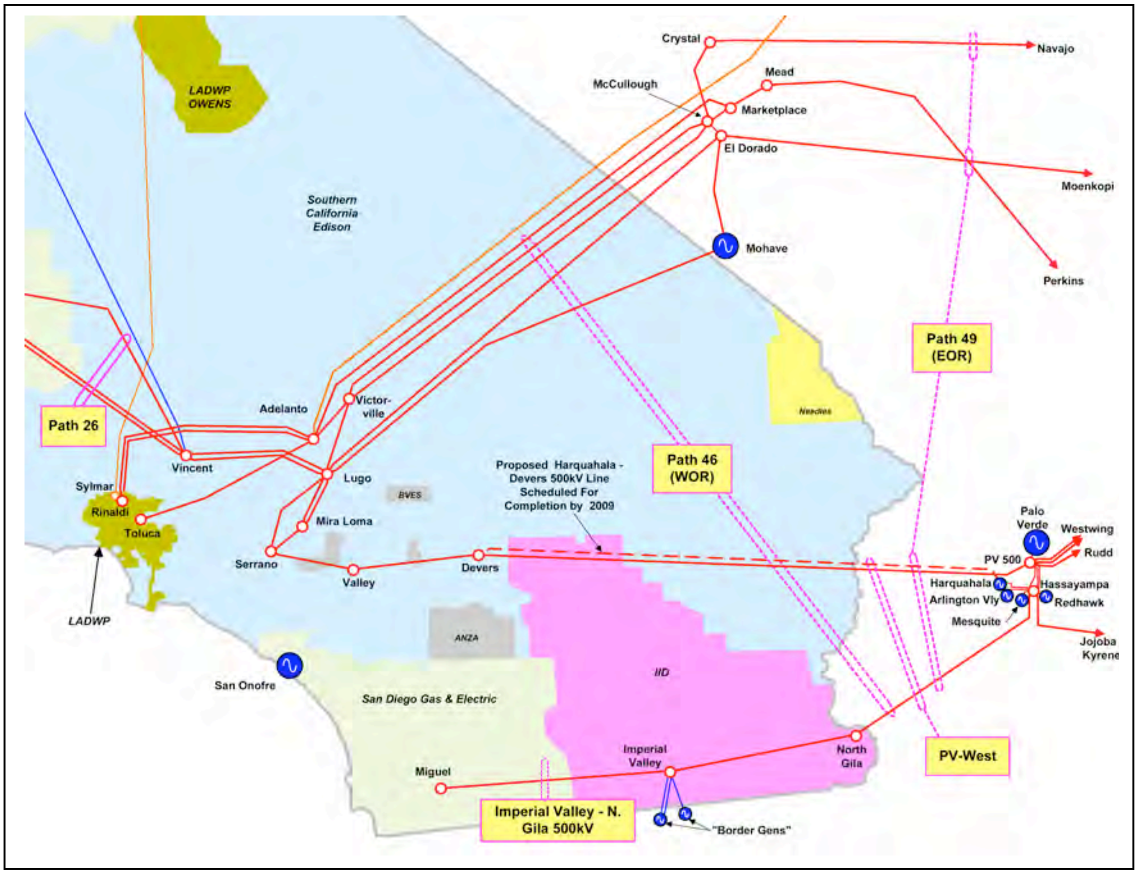
Source: California Independent System Operator DMA Report, Nov 5, 2004.

Transmission Limitations

The most expensive problem is the transmission physical limitations that restrict the amount of power that can be transferred on the Imperial Valley – Miguel 500 kV line and, to a lesser extent, on the Hassayampa – North Gila 500 kV line. The Hassayampa – North Gila – Imperial Valley – Miguel 500 kV system (also known as the Southwest Power Link) was originally constructed to move Palo Verde nuclear generation and other resources to loads all along the line. With deregulation came the rapid construction of new generation projects. New generators were constructed just across the border in Mexico south of the Imperial Valley 500 kV substation (Figure 1). During the 2000 – 2001 energy crisis, DWR offered to these plants contracts for firm delivery into the CA ISO market. Later, when the DWR was withdrawing from the business of acquiring power for the state, these contracts were assigned to the PTOs as firm resources. Now that the plants are scheduled by the PTOs for their load needs and these efficient plants are typically the most economical resource available, the PTOs have an economic incentive to schedule the entire plant to serve load in the forward markets, even if it is an unfeasible forward schedule. It is then left to the CA ISO to relieve the resulting congestion in real time.

Figure 1

Southern California Transmission



Imperial Valley – Miguel

To reduce congestion, some relatively minor fixes were made by adding 500/230 kV transformer capacity at Imperial Valley and (more recently) at Miguel. A new 230 kV line from Miguel to Mission has recently been placed into service (on a temporary basis) ahead of schedule. These transmission upgrades have increased the Imperial Valley-to-Miguel 500 kV line limit to the point where congestion costs are significantly reduced. Although not broken out by congestion cause, the CA ISO mentions in the April - May 2005 DMA report that total congestion costs for January - May of 2005 are tracking at about half the level encountered for the same months of 2004.

Appendix B of the CA ISO's *Intra-Zonal Congestion Management Impacts Report* lists congestion costs for August 2003 through July of 2004.[13] These costs include redispatch

[13] The ISO has begun to differentiate commitment instructions for (i) system and (ii) zonal, and (iii) local net short requirement separately for cost allocation purposes. However, data presented by the ISO represents MLCC total costs, without identifying the breakdown of the three components. These percentages may therefore be high.

and MLCC (but not RMR) totaling to just over $30M for the 12 month period. Were these costs to have continued, they would have supported $300M worth of a transmission construction project to relieve the physical constraint (assuming a ten percent carrying charge).

The next major increment of transmission has been identified by San Diego Gas and Electric (SDG&E) as a new line from the Imperial Valley area to the central or northeastern part of SDG&E's system. By its nature and the nature of impacts on others, the selection, design, environmental, permitting, and construction processes are very slow and deliberate. Therefore, this line may not be completed before 2010.

Palo Verde West

To a lesser extent, congestion problems have been encountered on the two 500 kV lines west of Palo Verde (Figure 1). Ironically, congestion problems on the PV – West path are compounded when the border generators are DEC'ed for Imperial Valley – Miguel congestion and about 10 percent of that DEC'ed generation appears as increased congestion on the PV – West 500 kV lines.

A project to increase the rating of Path 49, also known as the EOR 9000+ project, is nearing completion of the WECC Phase 2 Rating approval process. This project involves upgrades of series capacitors and several other system improvements. As shown in Figure 1, the PV –West 500 kV lines are also part of Path 49.

A longer-term fix for the PV – West path is also underway. Southern California Edison is nearing completion of the WECC Phase 2 Rating process for a new 500 kV line from Harquahala (near PV) to Devers (Figure 1). This line will be rated at 1200 MW and will increase the total Path 49 rating by the same 1200 MW. SCE applied to the California Public Utilities Commission for a Certificate of Public Convenience and Necessity (CPCN) on April 11, 2005 for this project.

Other Observations From Operational Data

On March 29, 2004, more than 2000 MW of "border generation and PV area" generation was decremented in an attempt to relieve congestion on the PV West branch group. Although not stated, the border generation was more than likely DEC'ed for Imperial Valley – Miguel congestion. Also, actual flows on PV – West did not match well with the predictions from the congestion management program. Even with this decrementing action, the actual flow exceeded the PV – West rating (2,766 MW based on data provided by the CA ISO) by as much as 115 MW.[14] During this particular time period, there appear to be no major system maintenance or forced outages that would have contributed unusual congestion.

Generation additions in the Palo Verde area have been referenced in several paragraphs above. The following table summarizes these additions (and shows some minor differences in plant ratings and commercial operation dates depending on the source of such data).

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[14] According to CA ISO Operations Engineering, the 2,766 MW rating was in error and should have been 2,823 MW.

Table 2

Palo Verde Area Combined-Cycle Generation Additions

	WECC Significant Additions Reports[15]				Plant Ratings, Other		
Plant Name	Net Capacity, MW Net Capacity		Commercial Operation Date	Significant Additions Report (Year)	From CEC[16] 5/31/05	Powerflow Data[17] Net Capacity, MW	
	Summer	Winter				Pgen	Pmax
Redhawk	1006	1028	July 2002	2003	1060	864	984
Arlington	570	580	July 2002	2003	580	600	700
Mesquite I	625	625	June 2003	2004	625	494	691
Mesquite II	625	625	Nov. 2003	2004	625	494	691
Harquahala	836	860	Sept. 2003	2004	1170	1113	1128
TOTALS	3662	3718			4060	3565	4194

In addition to the Palo Verde area combined-cycle generation addition, the Palo Verde nuclear generation is being uprated during plant refueling cycles by replacing the steam generators with more efficient units. Units 1 and 3 are to be uprated to 1403 MW and Unit 2 will be uprated to 1400 MW. The uprates should total 150 MW.

[15] Western Electricity Coordinating Council, "Existing Generation and Significant Additions and Changes to System Facilities." [http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=19]. Select the year of interest and scroll down to the SIGADD**.pdf file.

[16] California Energy Commission, Proposed Generation Database, 05/31/05, [http://www.energy.ca.gov/electricity/WECC_PROPOSED_GENERATION.XLS].

[17] Western Electricity Coordinating Council, [http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=21]. Note: WECC login required.

CHAPTER 3: SOUTHERN CALIFORNIA EDISON AND LOS ANGELES DEPARTMENT OF WATER AND POWER INTERCONNECTION

Introduction

Limits on sales from Los Angeles Department of Water and Power (LADWP) to the CA ISO for the time frames investigated were probably due to maintenance outages and outages required for the conversion of the Pacific Direct Current Intertie (PDCI) terminals at Sylmar. However, when analyzing sales from LADWP to SCE (Scheduling Coordinator Identifier (SCID): SCE2), they appear to be relatively small when compared to schedule adjustments made for congestion management. Data were not available to determine if, at any time, LADWP had additional capacity for sale to SCE, and data were not available to determine flows and therefore available and unused transfer capability across the constrained path at Sylmar. We suspect that the heavy flows that were observed may be a result of bilateral contracts between SCE and LADWP. These bilateral exchanges do not make it into the CA ISO market data and therefore the data provided does not paint a complete picture of LADWP's contributions to the market.

During December 2003, LADWP took of one of the 600 Megavolt-ampere (MVA) 220/230 kV transformer banks at Sylmar out of service for maintenance. During this three-week outage, the CA ISO incurred $9.8 M in congestion costs. These congestion costs are approximately the same as the cost of installing a new transformer. If a new transformer had been available prior to the maintenance outage these congestion charges could have been avoided.

In the latter part of 2004 additional congestion costs at Sylmar were incurred during the conversion of the PDCI terminals. These costs were probably unavoidable and occurred even though the conversion was performed during the time of the year when PDCI capacity was least needed.

Possible transmission upgrade options to increase the transfer capability between SCE and LADWP could include:

1. A fourth 220/230 transformer at Sylmar (which would likely provide limited benefits now that the third bank (Bank G) is in service).

2. A new 500 kV line from Adelanto to Lugo (which would likely add to Lugo – South congestion).

3. Remove and replace the 230 kV “emergency tie” from Velasco to Laguna Bell with a 2156 ACSS double circuit tower line.[18] This option would require the addition of 220/230 transformers at Velasco and possibly the replacement of many circuit breakers on the SCE and LADWP systems. One concern with this potential interconnection is that it may negatively impact the fault currents on LADWP’s and SCE’s systems.

Description of Interconnections and Path Ratings

Major interconnections between LADWP and SCE are at Sylmar, on the Victorville – Lugo 500 kV line, and at the El Dorado 500 kV bus on the McCullough – El Dorado 500 kV line in southern Nevada (Figures 2 and 3). There is also a 50 MW phase shifted 230 kV interconnection at Inyo, and one seldom used 230 kV emergency interconnection from Laguna Bell to Velasco. The Sylmar 220/230 kV interconnection was originally designed to provide a path whereby SCE and the municipal utilities in southern California that are interconnected with the SCE system could schedule their allocations of the PDCI when the PDCI terminals were connected only to LADWP’s Sylmar bus.

Figure 2

Southern California Interties

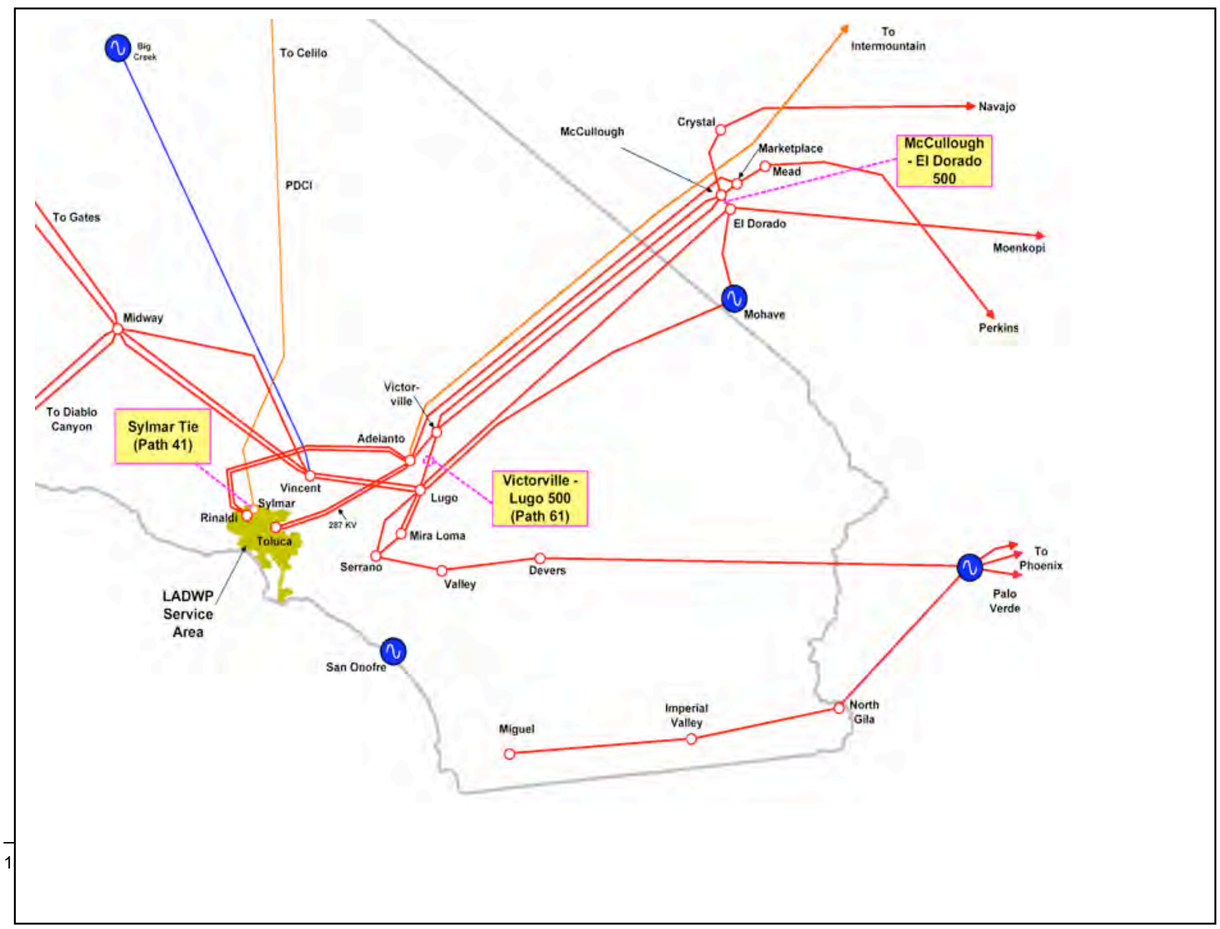
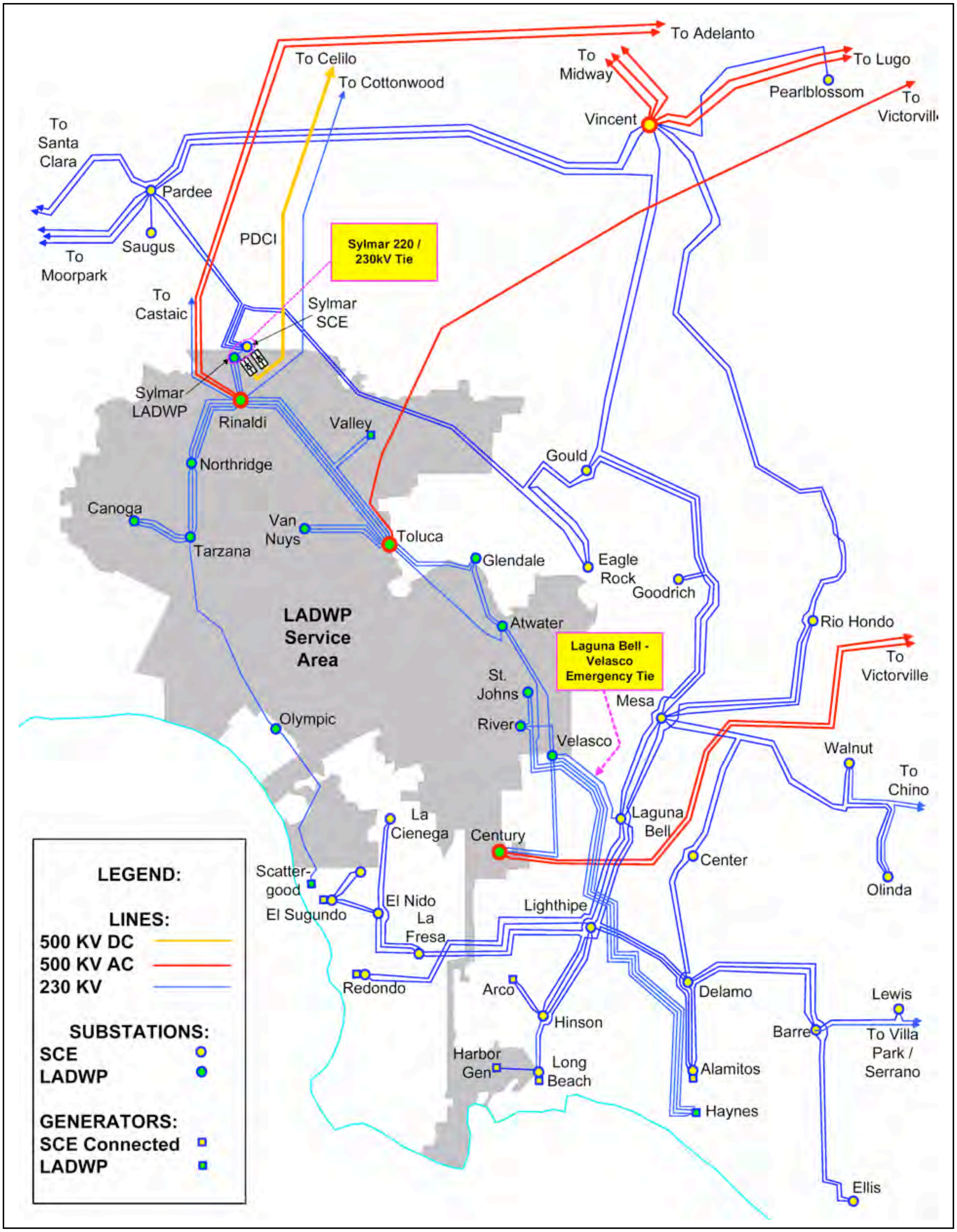


Figure 3

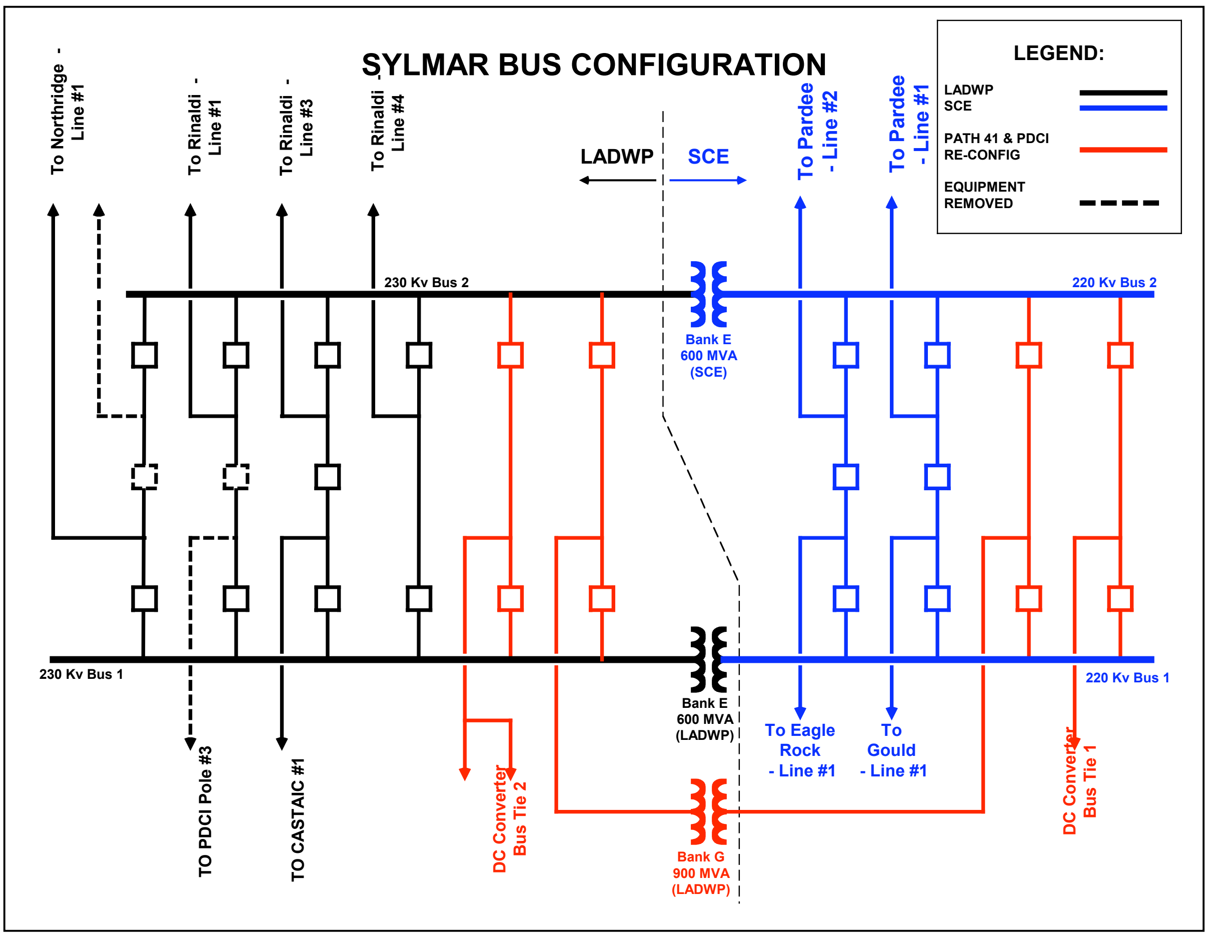
SCE/LADWP Transmission Detail



Prior to the end of 2004, facilities at Sylmar consisted of two 220/230 kV transformers (Banks E & F) each rated at 600 MVA continuous with emergency ratings of 800 MVA; these two transformers comprised WECC Path 41 which was rated at 800 MW. In the latter part of 2004, LADWP completed installation of Bank G, a 900 MVA transformer with an emergency rating of 1156 MVA. A representative of LADWP stated that LADWP needed the transformer for reliability purposes and paid for the entire cost of the project. A one-line diagram of the new configuration is shown in Figure 4.

Figure 4

Sylmar Bus Configuration



With the transformer addition, Path 41 is now rated at 1,600 MW. As shown in LADWP's Path 41 Upgrade study,[19] the critical contingencies then become the 230 kV lines out of Sylmar SCE to Pardee, Eagle Rock, and Gould when the 1,600 MW

[19] Los Angeles Department of Water and Power, December 17, 2003, *Comprehensive Progress Report On Sylmar to SCE-Path 41 Upgrade*.

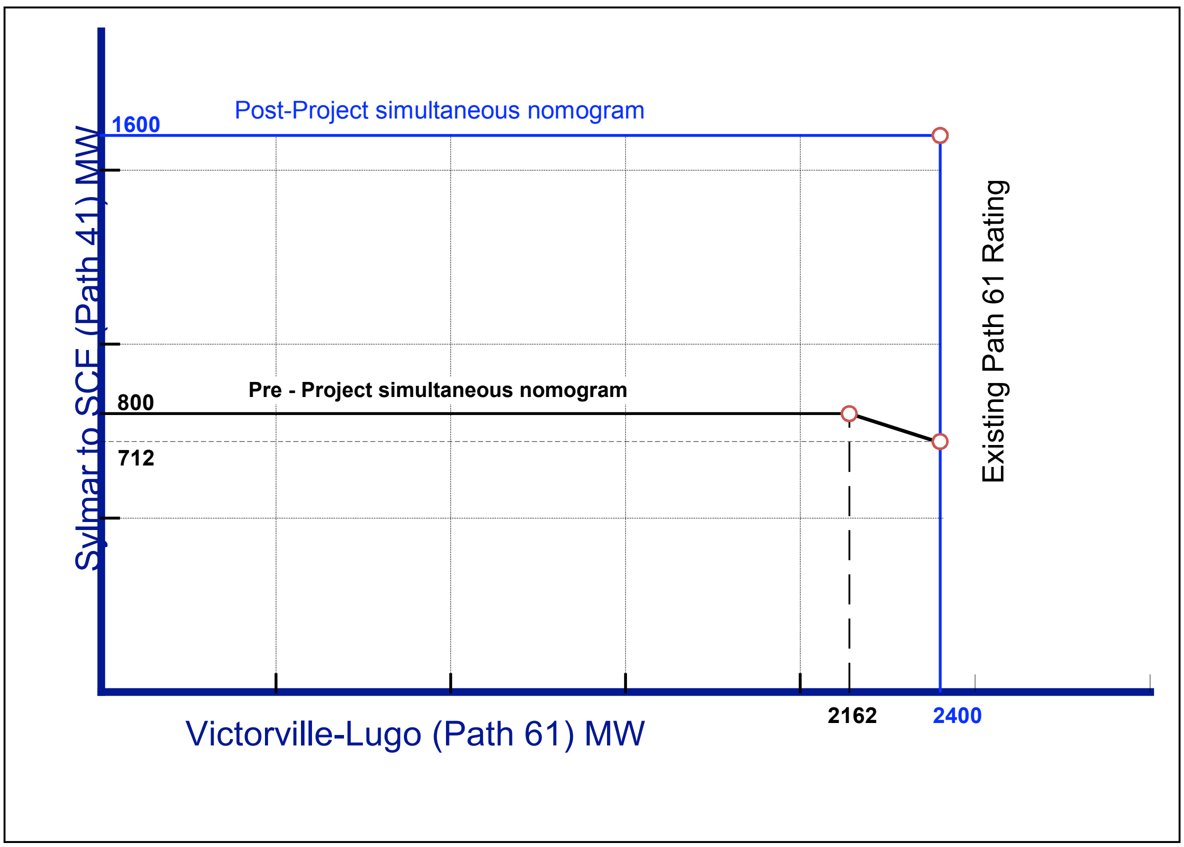
Path 41 transfer is simultaneous with the PDCI, operating at 3,100 MW north-to-south. With this flow configuration, the 220/230 kV transformers are no longer limiting.

Even though the nominal system voltages are the same between the Sylmar buses, SCE tends to operate its 230 kV system at a slightly lower voltage. SCE has been increasing its operating voltages in the Los Angeles Basin 220 kV system over the years so that it now operates closer to LADWP's 230 kV system. However, if the systems were directly connected at Sylmar, uncontrolled reactive power would flow from LADWP to SCE. For this reason, the LADWP and SCE systems are isolated by the 220/230 kV transformers. These transformers serve to keep the reactive power flows within limits.

The Victorville – Lugo 500 kV tie (Path 61) has a transfer capability of 2,400 MW from Victorville to Lugo and 900 MW from Lugo to Victorville. The Victorville – Lugo rating is based on the line's emergency loading after a Lugo – Mohave or Lugo – El Dorado 500 kV line outage.

Figure 5

Sylmar – SCE Simultaneous Nomogram



Before Bank G went into service, there was a nomogram relationship between Path 41 (Sylmar) and Path 61 (Victorville – Lugo). See Figure 5. The diagram also shows that the Path 41 uprate project removed the simultaneous path relationships, for example, there are no longer reductions at the corner point and the path's ratings and operation are now independent.

Path Flow History

Flow data for total flow out of Sylmar SCE into the SCE system to Pardee, Gould, and Eagle Rock were received from the CA ISO. Data were not received for the Sylmar 220/230 transformers because these transformer paths are not monitored by the CA ISO, therefore no analysis could be performed to verify congestion relief procedures relative to these transformers.

Hourly flow information was also received from the CA ISO for the Victorville – Lugo 500 kV line (Path 61). However, the CA ISO maintains that any graphical or numerical listing of this data cannot be divulged according to the terms of a confidentiality agreement. What can be described is that the path did not reach its rated limit anytime in 2003 or 2004.

Congestion Costs

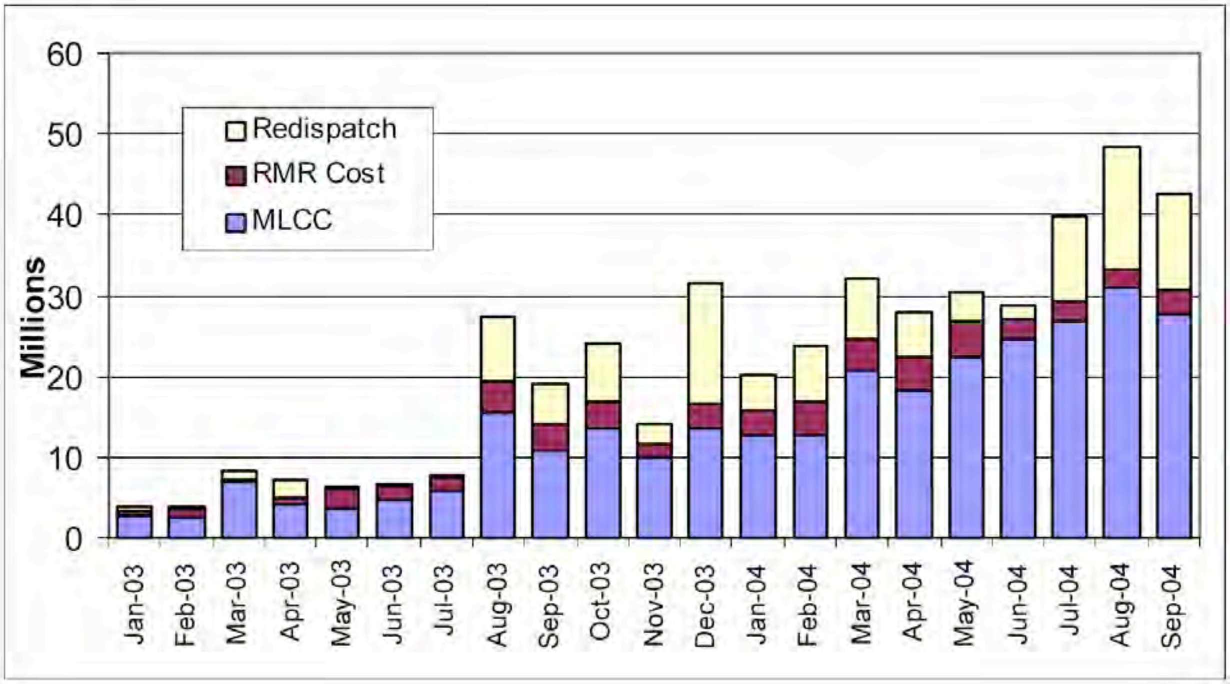
Hourly market pricing information was received from the Energy Commission under a non-disclosure agreement. However, the best information about congestion costs and causes is contained in the CA ISO's DMA reports, which can be found in the market analysis section of the CA ISO website. The hourly market data received from the Energy Commission confirmed some of the decremental ("DEC'ing," decrementing; reducing generation output of upstream units) actions but did not contain the entire cost picture.

Congestion costs encountered by the CA ISO include the incremental ("INC'ing," incrementing; increasing generation output of downstream units) and DEC'ing costs also referred to as redispatch costs. In addition to the redispatch component, two additional cost components are:

1) Reliability must run (RMR, assumed to be additional operations and maintenance (O&M) costs for fuel and other operational costs).
2) Costs from calling on MLCC machines to adjust generation to relieve congestion (as opposed to their primary purpose of serving the "net short" position).

Figure 6

CA ISO Congestion Costs (Jan 2003 – Sept 2004)



Source: California Independent System Operator, Market Analysis Report, November 5, 2004.

As shown in Figure 6, redispatch costs are a relatively small component of the total congestion cost picture. The RMR component is likely the O&M charges associated with ramping RMR units, where available, to ease congestion. The MLCC component occurs when generators that are normally brought on line at the request of the CA ISO to meet the daily "net short" position are instead called to increase output for congestion relief. These units may also provide net-short capacity but the call was made for congestion purposes. In a report on intra-zonal congestion, the CA ISO attributes $35,087,532 of MLCC costs to congestion at Sylmar for the time period of August 2003 through July 2004.[20] Total congestion costs for the months shown in Figure 6 total just over $440 million.

Figure 7 takes the redispatch costs shown in Figure 3-5 and breaks them out by location or cause. Note the large redispatch cost for December, 2003, related to a "three week Sylmar bank outage" according to the September, 2004 DMA report. Although not specified in the CA ISO document, it is assumed that this outage occurred on one of the 600 MVA 220/230 kV banks. Interpretation from this graph

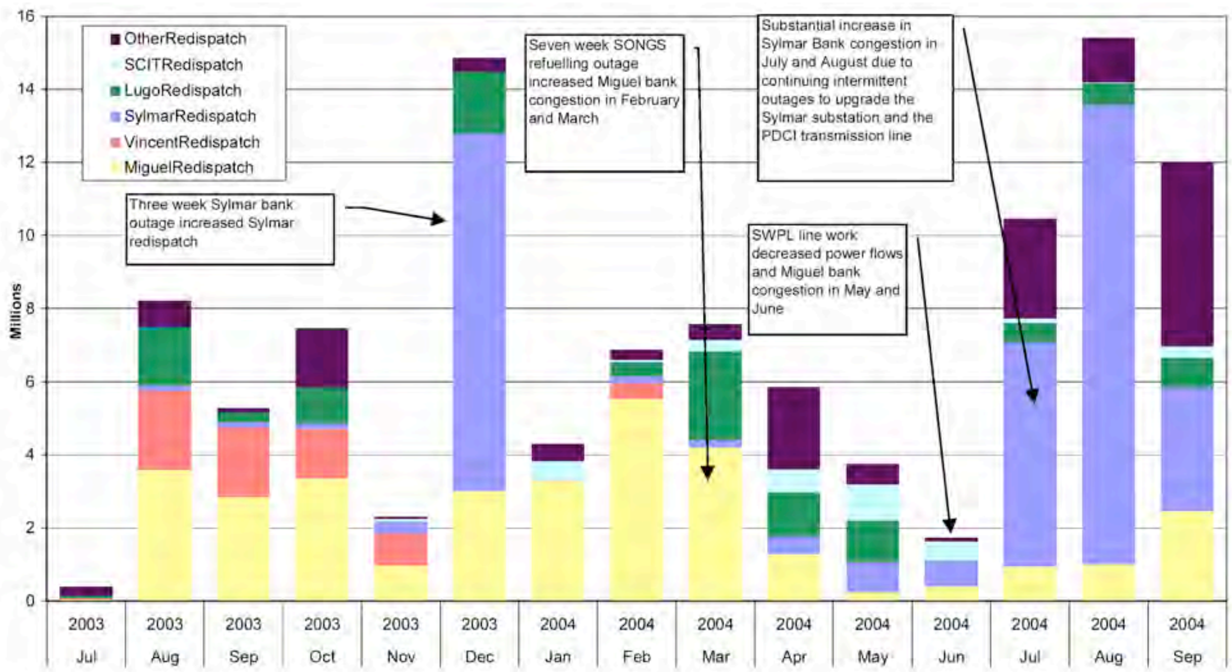
[20] California Independent System Operator, Revised Oct. 7, 2004, *Intra-Zonal Congestion Management Impacts*.

shows a congestion cost, primarily due to the three week-outage, of approximately $9.8M. During this time, 56,148 megawatt hours (MWHRs) were DEC'ed at the Nevada – Oregon Border (NOB) of the PDCI at a cost of $1,162,986. Although this data was not provided, one would have to assume that the DEC'ing was taken on the LADWP 2,000 MW direct current (DC) terminal to reduce flow and congestion across the 220/230 kV transformers. A larger part of the cost involved INC'ing of 214,033 MWHRs from generation at Mandalay and Ormond Beach, at a cost of $6,606,332. Between August 2003 and September 2004 the total congestion costs attributable to the Sylmar interconnection were approximately $32M.

Figure 7

Congestion Related Redispatch Costs by Location

(July 2003 - Sept. 2004)



Source: California Independent System Operator, Market Analysis Report, November 5, 2004.

Also noted in Figure 7, the months of July, August, and September 2004 show large components of congestion costs at Sylmar due to outages of the PDCI terminals for upgrades, to the new three-terminal configuration. As noted on the chart, the congestion is due to intermittent outages of the PDCI terminals during the reconfiguration of the DC line. During outages of the 1,100 MW terminal connected to SCE's Sylmar bus, and subsequent transfers of PDCI allocations to LADWP's 2,000 MW terminal, the most effective congestion relief curtailments were on SCE's schedules on the PDCI and INC'ing generation in the western part of SCE's system at Mandalay and Ormond Beach. Note that during this time the new 900 MVA Bank G was not yet in service.

When the PDCI was initially put in service with a rating of 1,600 MW and then later upgraded to 2,000 MW, all of the DC terminal equipment was connected to the Sylmar – L.A. bus; the PDCI allocations for SCE and certain municipal utilities connected to the SCE system flowed through the two 600 MVA transformers. When the PDCI was expanded to 3,100 MW, the 1,100 MW southern expansion terminal was connected to the Sylmar – SCE bus. The new three-terminal configuration that went into service in December 2004 splits the southern DC terminations with 1,550 MW of capacity connected to the LADWP Sylmar 230 kV bus and 1,550 MW of capacity connected to SCE's Sylmar 220 kV bus. For operation in 2005 and beyond, transfers across the 220/230 kV transformers should be reduced and congestion costs minimized.

However, for the future, there is one factor that has the potential to impact congestion at Sylmar: LADWP's re-powering program at the Valley, Scattergood, and Haynes powerplants. LADWP is in the process of dismantling the older boiler/steam units and replacing them with more efficient combined-cycle units. As this re-powering progresses, it could result in more LADWP generation successfully bid into the CA ISO market against the older, less efficient generators connected to SCE's system. Generator retirements in SCE's area may compound this problem.

Potential Transmission Improvements

Additional transformer capacity could be installed at Sylmar to reduce congestion. However, as noted in LADWP's Path 41 Report, when the PDCI is operating at its full 3,100 MW rating the constraints will have moved onto the SCE 230 kV lines to Pardee, Gould, and Eagle Rock.[21] Only when the PDCI is at lower levels could additional transformer capacity be of use at Sylmar. LADWP has indicated that if SCE desires additional 220/230 kV transformer capacity, SCE would be responsible for the costs. Additional transformer capacity and a subsequent Path 41 rating increase would likely result in a new nomogram between Path 41 and the PDCI quantity received at the SCE DC terminal and would likely require a change to the Path 41 – Path 61 nomogram shown in Figure 5. This nomogram would reflect that the transfer constraint would likely become the loading on lines from Sylmar to Pardee, Gould, and Eagle Rock. Balanced flow on these lines would be dependent upon Ormond Beach and other generation levels. To remove nomogram restrictions on the lines out of Sylmar, additional lines to Pardee and Mesa could be required. Unless additional rights-of-way are already controlled by SCE, new lines may be difficult to construct.

[21] Los Angeles Department of Water and Power. December 17, 2003. *Comprehensive Progress Report On Sylmar to SCE-Path 41 Upgrade*.

Another alternative to this option might be to add flow control reactors or phase shifters at Sylmar to control flows into SCE at Sylmar so that interchanges between LADWP and SCE are directed onto the Victorville – Lugo 500 kV line(s). One drawback to this option is that it would increase the south of Lugo path loading and potentially increase congestion south of Lugo.

There is an emergency 230 kV tie between SCE's Laguna Bell Substation and LADWP's Velasco Substation. This tie has not been used for many years and is only maintained for emergency purposes. To determine if closing this interconnection would be beneficial, some preliminary power flow studies were done. Starting from a case[22] with high transfers from LADWP to SCE at Sylmar, the existing emergency tie was closed and promptly loaded to 250 percent of its summer rating. A rebuild of the line to double circuit 230 kV was then modeled with a 2156 ACSS conductor (rated at 1237 MVA) to take extremely high loading and operating temperatures. Based on Navigant Consulting, Inc.'s preliminary analysis, one additional 230 kV line from Haynes would also need to be looped into Velasco. Each of the Velasco – Laguna Bell 230 kV ties loaded to 678 MW and substantially off loaded the Sylmar banks, indicating that there may be difficulty in keeping too much power from flowing on the tie from LADWP to SCE. An outage of one tie line resulted in 1,256 MW (2485 amps) on the remaining line. At this transfer level, a Velasco – Laguna Bell 230 kV double line outage does not overload the Sylmar 220/230 kV transformers. This tie would have the added benefit of off loading the south of Lugo path. The down side of this interconnection is that it may negatively impact the fault currents on LADWP's and SCE's systems. Many 230 kV breakers in the area are known to be near their interrupting limits and a tie this close to generation will likely result in the need for breaker replacements.

Another way to increase the transfer capability between the LADWP and SCE systems would be construction of a new line from Victorville to Lugo or from Adelanto to Lugo. Although the Victorville—Lugo path shows no congestion, peak loadings on this path reached 90 percent of the path rating during 2003 and 2004.[23] These high flow levels do indicate the potential for congestion to occur in the future. At the very least, it would be prudent to acquire right-of-way for a new line in this area.

[22] Case derived from WECC 08 HS2 from PV-DV2 Study Cases.

[23] Based on confidential path flow information provided by the CA ISO.